Hudson's Bay Oil and Gas Company Limited 1971 Annual Report

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CONTENTS

ANNUAL MEETING OF SHAREHOLDERS

The Annual Meeting of Shareholders will be held at the Head Office of the Company on Friday, April 28, 1972 at 11:30 a.m.

Financial and Operating Highlights

	1971	1970	Increase (Decrease) Per Cent
Financial			
Gross Operating Revenues	$95,307,000	$84,190,000	13.2
Funds Generated from Operations	$51,180,000	$44,607,000	14.7
Per Common Share	$ 2.72	$ 2.36	15.3
Net Earnings	$23,155,000	$20,170,000	14.8
Per Common Share	$ 1.18	$ 1.02	15.7
Dividends Declared	$11,561,000	$10,647,000	8.6
Per Preferred Share	$ 2.50	$ 2.50	—
Per Common Share	$ .55	$ .50	10.0
Capital Expenditures	$39,359,000	$37,364,000	5.3
Exploration Expenses	$ 8,972,000	$ 8,321,000	7.8
Operating			
Crude Oil and Natural Gas Liquids Production — Net (Barrels per day)	63,809	60,168	6.1
Natural Gas Sales — Net (Millions of cubic feet per day)	328.8	317.0	3.7
Sulphur Sales — Net (Long tons per day)	814	917	(11.2)
Pipe Line Throughput (Barrels per day)	90,463	81,930	10.4
Oil and Gas Rights (Net acres at year end)	28,657,000	22,691,000	26.3
Proved and Probable Reserves — Net (At year end)			
Crude Oil and Natural Gas Liquids (Barrels)	389,144,000	393,462,000	(1.1)
Natural Gas (Millions of cubic feet)	3,177,000	3,211,000	(1.1)
Sulphur (Long tons)	9,903,000	9,919,000	(0.2)

President's Report

Hudson's Bay Oil and Gas achieved record levels of operating volumes, revenues and earnings in 1971 while continuing extensive exploration programs in western Canada, the Arctic Islands and offshore eastern Canada.

Financial Results

Net earnings for 1971 were $23,155,000, a gain of 14.8% over the prior year and, after deducting preferred dividends, amounted to $1.18 per common share. Funds generated from operations advanced 14.7% to $51,180,000 or $2.72 per common share. Internally generated funds were sufficient to provide 98% of the funds used for capital expenditures, dividends and required retirement of long term debt and the Company retained a strong working capital position at year end.

Gross operating revenues were $95,307,000, up $11,117,000 or 13.2%. Crude oil production increased because of a growing market demand and because of production from new wells in several fields. These production gains, together with a general price increase that became effective late in 1970, led to a substantial advance in crude oil revenues. Higher production at several of the Company's gas plants and a general increase in the price of condensate led to gains both in natural gas and natural gas liquids revenues. Pipe line and product distribution revenues also were significantly higher than in 1970.

Capital Expenditures and Exploration Expenses

Capital expenditures and exploration expenses totalled $48,331,000 compared with $45,685,000 in 1970. Capital expenditures were $39,359,000, up $1,995,000 or 5.3%, as an increase in investments to expand production and pipe line facilities was partially offset by a decrease in expenditures for acreage acquisitions.

The largest item in the 1971 capital spending program involved construction of the third processing plant in the Kaybob South gas field, in which the Company will hold an approximate 18% interest. Start-up of this partner-operated plant, originally scheduled for mid-1971, was delayed until early 1972 because of construction problems. Exploration expenses advanced 7.8% to $8,972,000 due to increased geophysical activity.

In 1971 the Company participated in 64 exploratory tests, of which 15 were successful. The most significant discoveries were oil in the Shekilie and Amigo areas of northwestern Alberta and gas in the West Edson area of west-central Alberta. Four exploratory tests were drilled under farmout arrangements with Panarctic Oils Ltd. at no cost to the Company on the large spread of acreage in the Arctic Islands in which the Company holds interests. Although these tests were unsuccessful, this large acreage spread continues to provide good exposure to hydrocarbon discoveries in the Arctic.

Expenditures associated with protection and conservation of the environment continued at a high level in 1971. Over the next several years even larger expenditures are anticipated in order to maintain or improve environmental standards.

Plans for 1972

Approximately the same level of capital expenditures and exploration expenses is expected in 1972 as in 1971. An increase in exploratory and development drilling expenditures and geophysical expenses will be offset by a reduction in gas plant expenditures resulting from the completion of Kaybob South Plant No. 3. However, continuing programs to expand capacity and to improve operating efficiency and pollution control at existing gas plants will involve substantial capital outlays.

In addition to its direct outlays, the Company will continue to obtain discovery exposure through exploratory wells drilled on its lands by others in order to earn interests in these holdings. Of particular significance, two deep exploratory tests on Prince Edward Island will be paid for by another company and its associate during 1972 as part of a program to earn an interest in the Company's jointly-owned 10.4 million acre block that includes the Island and surrounding waters.

Industry Review and Outlook

Canadian hydrocarbons production continued to grow in 1971 with exports to the U.S. providing the major impetus. This pattern is expected to continue through 1972. Production of crude oil and condensate increased by about 7% in 1971 and a further gain of approximately 10% is anticipated in 1972. Sales of natural gas grew by approximately 13% in 1971 and should be followed by an approximate 9% gain in 1972. Production of liquefied petroleum gases (propane and butane) should grow by over 10% in 1972, after a 15% increase in 1971. Except for certain seasonal imbalances involving natural gas liquids, demand for western Canadian hydrocarbons remains strong.

Western Canadian sulphur production was up by 20% in 1971 and scheduled plant start-ups and expansions suggest a 30% to 40% gain in 1972. Sulphur marketing conditions continued to deteriorate in 1971 and a relatively small increase in sales is expected in 1972. This will result in acceleration of the already rapid growth of western Canadian sulphur inventories.

Interest in Canadian exploration activity remained at a high level during the year. While activity in the western Provinces remained at approximately the same level as in 1970, major new commitments were made to exploration in Canada's frontier areas in the far north and off the east coast. A similar pattern appears likely in 1972 but the longer-term trend in exploration activity will be largely dependant on two factors. The first of these will be the industry's success in finding new petroleum reserves in western Canada or in the new frontier areas. The second factor will be the degree to which selling prices reflect the rising costs of finding, developing and producing oil and natural gas and of meeting increasingly stringent pollution control requirements.

The need for higher oil and gas prices is gaining greater recognition within the industry and in certain consuming and governmental sectors, but the extent and timing of future price increases remains uncertain. Over the past decade, crude oil prices have not kept pace with rapidly rising finding, developing and producing

costs. Natural gas, with its clean-burning characteristics, consistently has been priced at unreasonably low levels when compared to alternate fuels with higher sulphur content. This underpricing has the dual effect of encouraging excessive consumption in low priority uses and of discouraging exploration for new supplies. Due in large measure to forecasts of extremely rapid growth in demand for low-priced natural gas by eastern utility and industrial consumers, the National Energy Board recently declared that Canada has no additional exportable surplus of natural gas. This declaration will reduce competition among potential purchasers of natural gas for export markets and will retard the trend toward more realistic prices.

One encouraging development in gas pricing was an arbitration award made late in 1971 whereby a number of Alberta producers received a substantial price increase under price redetermination provisions of their sales contracts. In handing down their decision the arbitrators emphasized the fact that western Canadian gas is underpriced in the markets that it serves. This decision has particular significance to the Company as approximately 35% of its present gas sales volumes are sold under contracts that will be eligible for price redetermination during 1973.

The outlook for the general business climate is clouded by the profusion of legislative actions and proposals by the Federal government during 1971. Considerable uncertainty has been created by the potential consequences of the complex new tax act and by major changes proposed in the areas of intercorporate competition, foreign ownership and labour practices. Of more general concern is the apparent trend of the Federal government toward the substitution of decisions by administrative agencies for the free exercise of competitive business judgments. Another area of uncertainty for the petroleum industry is the possibility of higher royalties on Alberta production of oil and gas following the decennial redetermination of rates scheduled for April, 1972. In considering changes in the royalty rate structure it is anticipated that the Government will be mindful of the need to maintain adequate incentives to encourage the search for new reserves.

Canada continues to have good exploration prospects and potential opportunities for market growth are excellent. If government regulations and controls are applied in a constructive and rational manner the decade ahead will see continued rapid expansion of the Canadian petroleum industry so that it may continue to satisfy a large portion of the energy demands of the Country.

Directors and Employees

At the annual meeting of the shareholders held in Calgary on April 28, 1971 the number of directors of the Company was increased from ten to twelve. L. J. Richards, who retired as President in 1970, did not stand for re-election. The resulting three Board vacancies were filled by the election of H. W. Blauvelt, a former Senior Vice-President of the Company and now President of Conoco Chemicals Division and a Director of Continental Oil Company; G. H. Blumenauer, Chairman of the Board of Directors and President of Otis Elevator Company Limited; and S. G. Olson, Executive Vice-President of the Company. The Board expressed its deep appreciation to Mr. Richards who contributed so much to the Company's progress during his twenty-three years of service, particularly during his five years as President and Chief Executive Officer.

The Directors wish to record their recognition and appreciation of the contributions made by employees throughout the Company. The successful operating results and growth achieved by the Company during the year are attributable in large measure to the dedicated application of their knowledge and skills.

Submitted on behalf of the Board of Directors.

D G Jones

President

February 25,1972 Calgary, Alberta

Exploration

Petroleum Exploration — Petroleum exploration expenditures, including both capital and expense items, totalled $17,775,000 in 1971, down $1,150,000 or 6.1% from the previous year. Expenses increased by $545,000 to $8,526,000, principally due to greater geophysical activity, but this increase was more than offset by a $1,591,000 decrease in capital expenditures for acreage acquisitions which totalled $4,067,000 for the year. Exploratory drilling expenditures, at $5,182,000, were essentially unchanged.

The Company's expenditures for petroleum exploration were largely concentrated on prospects in western Canada, which includes Alberta, British Columbia, Saskatchewan and the southern portion of the Northwest Territories. The Company also conducted marine geophysical surveys on the Labrador Shelf and near Anticosti Island off Canada's east coast and substantially increased its eastern Canadian offshore and Arctic Islands acreage holdings. In addition to programs financed by Company expenditures, significant amounts of drilling on Company acreage in western Canada and in the Arctic Islands and a seismic program in eastern Canada were undertaken through farmout programs in which the costs were borne by others in order to earn interests in the acreage.

Exploratory completions totalled 64 gross wells, including 26 farmout wells. The geographical distribution of the exploratory tests was 41 in Alberta, 13 in British Columbia, 4 in the Arctic Islands, 4 in Saskatchewan, and 2 in the southern portion of the Northwest Territories. The exploratory wells resulted in 15 gross (9.2 net) discoveries or extensions and 49 gross (23.0 net) dry holes.

Exploration Cash Outlays

	Expenses	Capital Expenditures	Total
Petroleum Exploration	$8,526,000	$9,249,000	$17,775,000
Minerals Exploration	446,000	—	446,000
Total	$8,972,000	$9,249,000	$18,221,000

Exploratory Well Completions

	1971		1970	
	Gross	Net	Gross	Net
Oil	7	5.5	5	2.7
Gas	8	3.7	15	8.1
Dry	49	23.0	46	24.0
Total	64	32.2	66	34.8
Average Depth	6,533 feet		5,092 feet	

The 15 successful exploratory tests were located in western Canada; 7 discovered oil and 8 discovered gas. The most significant discoveries were made in the Shekilie and Amigo areas of northwestern Alberta and in the West Edson area of west-central Alberta.

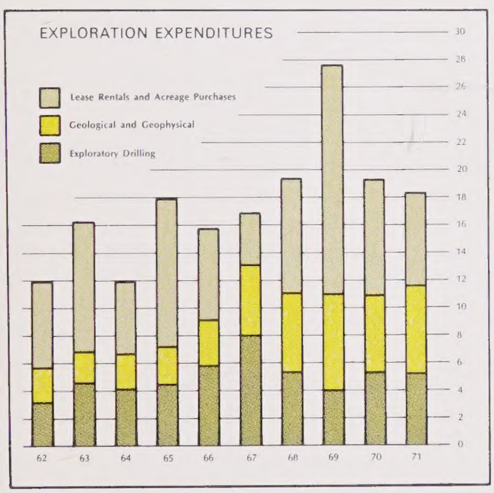
Lower right, a Company geophysical crew carrying out a seismograph survey in the farming area of southern Alberta.

Lower left, the mast of the drilling rig is being raised in preparation for drilling at the Irishtown location in Prince Edward Island.

In the Shekilie area, where the Company drilled a discovery well in 1970, an additional 4 oil wells were completed in separate Keg River reefs. This field is 15 miles northwest of the Zama Lake oil field. The Company has a 100% interest in 57,300 acres in the Shekilie area and a drilling program is currently underway to explore for other reefs on this acreage.

The Company also made a Keg River reef oil discovery in the Amigo area, approximately 10 miles northeast of the Shekilie field. This well was drilled on a 4,480 acre lease block in which the Company has a 50% interest. The Company subsequently acquired a 100% interest in an adjoining 8,320 acre drilling reservation at a cost of $351,000. Further exploratory drilling is in progress on these holdings.

In the West Edson area the Company drilled a Viking Sand gas discovery on a wholly-owned 5,760 acre lease block. The Company subsequently purchased an 8,960 acre drilling reservation adjacent to the discovery at a cost of $101,000 and also holds interests ranging from 41⅔% to 100% in several nearby lease blocks.



The Company participated in oil or gas discoveries or extensions in the Drake, Balsam and Velma areas of northeastern British Columbia and in the Richdale, Samson and Medicine Hat areas of Alberta. The Company holds interests varying from 25% to 50% in the tracts on which these wells were drilled. These discoveries are not expected to develop into major reserves.

Four exploratory wells were drilled in the Arctic Islands during 1971 on the 3.7 million acre spread in which the Company holds an interest. These tests were drilled on Melville, Cornwallis, Lougheed and Ellesmere Islands at no cost to the Company under the terms of a farmout agreement with Panarctic Oils Ltd. Although the four tests were unsuccessful, potential still remains for large discoveries on the Company's Arctic Islands acreage. Panarctic has options extending through 1973 to drill up to five further wells to earn additional interests. Upon completion of the Panarctic program the Company will retain minimum interests varying from 17% to 25% in the acreage subject to the farmout agreement. Industry activity remains high in the Arctic Islands, and a total of six wells are currently drilling. These wells will help to evaluate the Company's holdings.

Drilling on Company holdings in the barren terrain of Cornwallis Island in the high Arctic.

Exploratory activity is continuing on the 10.4 million acre block on and surrounding Prince Edward Island in which the Company presently holds a 50% interest. Two drilling locations were selected on the Island as a result of a geophysical survey carried out in 1971. The first test commenced early in 1972 near Irishtown and the second test is scheduled for later in the year. Costs of the geophysical survey and the two onshore tests are borne by another company and its associate as part of a $7 million program through which they will earn an aggregate one-third interest in the block. The $7 million commitment is expected to be fulfilled by the end of 1972, at which time the Company will retain a one-third interest in the acreage. Resumption of the offshore drilling program on this block has been delayed because of unavailability of a suitable drilling rig and is now scheduled for 1973.

During 1971, the Company acquired 9.1 million acres of petroleum and natural gas rights, of which 1.6 million acres were purchased at a cost of $4,067,000 and 7.5 million acres were obtained through filing and other acquisitions that did not require bonus payments. In western Canada the Company acquired a total of 1.3 million acres. The largest expenditures were $875,000 for 177,000 permit acres in northeastern British Columbia and $926,000 for 9,600 acres in the Shekilie-Amigo area. In the Arctic, the Company filed on 5.1 million permit acres off the coast of Baffin Island and purchased 78,000 acres for $473,000. The purchases included a 50% interest in an 81,000 acre block of onshore and offshore permits at the southern tip of Ellef Ringnes Island. This block lies approximately 8 miles east of the Panarctic King Christian gas discovery and 45 miles southeasterly of the Kristoffer Bay gas discovery on Ellef Ringnes Island.

In eastern Canada, the Company filed on 1.6 million permit acres off the east coast of Nova Scotia and purchased a 578,000 acre permit off the coast of Labrador at a cost of $116,000. In addition, the Company earned a 10% interest in 2.5 million acres on the Labrador Shelf and a 25% interest in 1.1 million acres in the Gulf of St. Lawrence by conducting marine seismic programs on these blocks. The Nova Scotia, Labrador and Gulf of St. Lawrence permits are in areas which

are subject to overlapping federal-provincial jurisdiction. The Company holds provincial rights on its acreage off the east coast of Nova Scotia and federal rights on its Labrador Shelf and Gulf of St. Lawrence permits acquired in 1971. Previously-acquired acreage off the East Coast, except for a minor amount offshore from Prince Edward Island, is covered by both federal and provincial rights.

During the year the Company surrendered or released its interests in 3.1 million acres of petroleum and natural gas rights. These included 2.2 million acres released after geological and geophysical evaluation, 262,000 acres surrendered under governmental regulations on conversion of permits and reservations to lease status, and interests equivalent to 663,000 net acres assigned to other companies as consideration for drilling on Company lands. In addition, 9,000 acres were transferred to the developed category. The largest blocks of acreage surrendered comprised 1.3 million acres in central British Columbia.

At year end the Company held 28,113,000 net acres of undeveloped petroleum and natural gas rights acquired at a total cost of $51,608,000. Rental payments in 1971 totalled $2,521,000.

UNDEVELOPED PETROLEUM AND NATURAL GAS RIGHTS

Net Acreage Holdings at December 31, 1971 (1)

	Crown Reservations and Permits (2)	Leaseholds	Hudson's Bay Company Lands (3)	Fee Lands	Total
BRITISH COLUMBIA	906,000	547,000	6,000	—	1,459,000
ALBERTA	558,000	1,669,000	1,483,000	85,000	3,795,000
SASKATCHEWAN	1,570,000	445,000	2,315,000	101,000	4,431,000
MANITOBA	—	—	700,000	89,000	789,000
NWT (including Arctic Islands and Baffin Offshore)	9,434,000	263,000	—	—	9,697,000
EAST COAST (4)	7,942,000	—	—	—	7,942,000
TOTAL	20,410,000	2,924,000	4,504,000	275,000	28,113,000

(1) The figures in this table are subject to modification by exploration agreements whereby others may earn an interest in the Company's acreage by undertaking certain exploratory work.

(2) Convertible into leases to the extent of approximately 50%.

(3) Held under an agreement which permits conversion to leases at any time up to December 31, 1999 without bonus payment.

(4) Offshore permits include 2,435,000 acres covered by Federal but not Provincial rights and 1,600,000 acres covered by Provincial but not Federal rights.

Minerals Exploration — The Company's 1971 minerals exploration program involved expenditures of $446,000 compared with $340,000 in 1970. The major portion of the program consisted of a search for copper deposits in the Yukon and the Northwest Territories. In 1972 activity will be directed principally toward British Columbia and a new program will be initiated in the southern portion of the Precambrian Shield area of east-central Canada.

Effective January 1, 1972 Continental Oil Company will join in the Company's minerals exploration effort. The joint venture will be on a 50-50 basis and since the exploration activity will be carried out in Canada, Hudson's Bay Oil and Gas will act as operator. This joint program will result in a more substantial exploratory effort and will provide both companies with a wider range of exposure to mineral discoveries.

Production

Development Drilling — The Company completed 41.9 net development wells in 1971 compared with 49.5 in 1970. The 1971 total comprises 27.2 in Alberta, 13.4 in Saskatchewan and 1.3 in British Columbia and includes 11.6 net farmout wells. Oil well completions aggregated 21.8 net wells or 52% of net development wells. Significant oil development projects included infill drilling in the Pembina, Bellshill Lake and Eagle Lake fields and additional development wells in the Kaybob South Triassic and Medicine River fields. Wells drilled under farmout agreements in the Lloydminster area resulted in 5.6 net oil wells. Gas well completions amounted to 10.6 net wells or 25% of net development wells. The most active areas of gas development drilling were in the Edson, Brazeau and Kaybob South Beaverhill Lake fields.

Development Well Completions

	1971		1970	
	Gross	Net	Gross	Net
Oil	80	21.8	73	23.8
Gas	30	10.6	57	13.4
Dry	25	9.5	29	12.3
Total	135	41.9	159	49.5
Average Depth	4,703 feet		5,318 feet	

Crude Oil — The Company's net crude oil production averaged 48,846 barrels per day, a gain of 3,286 barrels per day or 7.2% over 1970 production. This increase is attributable to higher allowable production from existing wells in Alberta, production from new wells completed in 1971 and a full year's production from wells completed in 1970. These gains were partially offset by productivity declines in the Milligan Creek area of British Columbia and lesser declines at certain other fields.

Installation of enhanced recovery facilities, designed to improve or maintain producing rates and ultimately recover a larger proportion of the oil-in-place, was completed in one pool during the year and was commenced at three additional pools with completion anticipated early in 1972. In several other fields existing facilities were expanded to take advantage of increased allowable production rates. A central water injection plant was constructed in the Pembina Field to supply several waterflood projects. This facility will reduce operating costs and provide increased flexibility and productivity. Further engineering studies using newly developed techniques were carried out on pools in the Zama Lake Field during the year. These studies indicate that the major enhanced recovery scheme previously planned for the Zama Lake area would not perform as originally contemplated and that it will be necessary to substantially reduce the scope of the project.

The Company continued to emphasize unitization projects which achieve economies by consolidating the operations of various owners within a pool as one unit. It participated in the formation of 12 oil and gas production units in 1971 and

expects to participate in 21 new or enlarged units currently being planned. The Company now holds interests in 200 units, 31 of which it operates.

The average wellhead price received by the Company for its 1971 crude oil production was $2.66 per barrel. This was up 24 cents per barrel from the 1970 average as a result of a general price increase that became effective late in 1970.

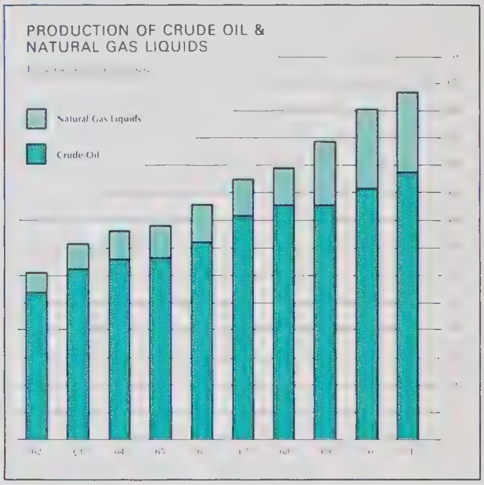
This maze of pipes and vessels shows the complexity of sulphur extraction facilities at a gas processing plant.

CRUDE OIL PRODUCTION — NET (Barrels Per Day)

ALBERTA	1971	1970
Pembina	8,106	7,990
Zama	3,660	3,809
Virginia Hills	2,602	2,442
Kaybob South Triassic	2,170	1,530
Sundre	1,964	1,843
Sturgeon Lake South	1,734	1,591
Shekilie	1,583	89
Medicine River	1,525	1,413
Nipisi	1,162	1,150
Innisfail	1,239	1,056
Bonnie Glen	1,208	1,136
Cessford	1,111	1,272
Sylvan Lake	1,029	795
Fenn Big Valley	894	768
Bellshill Lake	730	523
Swan Hills South	757	664
Others	6,839	6,272
Total	38,313	34,343

	1971	1970
BRITISH COLUMBIA		
Milligan Creek	3,372	4,241
Peejay	1,195	1,144
Wildmint	881	733
Others	317	290
Total	5,765	6,408
SASKATCHEWAN		
Success	782	838
Hummingbird	703	771
Others	3,266	3,182
Total	4,751	4,791
MANITOBA	17	18
TOTAL	48,846	45,560

Pilot plant construction at Lone Pine Creek to test one of the new processes which the Company is investigating in its continuing effort to reduce sulphur stack emissions.



Natural Gas and Associated Products — Sales of natural gas averaged 328.8 million cubic feet per day, up 11.8 million cubic feet per day or 3.7% over 1970. Increased gas sales resulted from revisions to the gas sales contract at Brazeau, higher production levels at Kaybob South Plants No. 1 and 2 and a full year's production from other plants placed on stream in 1970. These increases were partially offset by reductions in nominations from gas buyers in certain other fields. The average price obtained for 1971 gas sales was 15.6 cents per thousand cubic feet compared with 15.5 cents in 1970.

Condensate production averaged 11,934 barrels per day, essentially unchanged from 1970, while LPG production (propane and butane) advanced 11.4% to 3,029 barrels per day. Condensate and LPG production increases resulted from an upward adjustment in the Company's ownership interest in Kaybob Plant No. 2, from better operating performance at Kaybob Plants No. 1 and 2 and from increased production levels at Lone Pine Creek and several other fields. However, the gains in condensate production were essentially offset by lower recoveries at Whitecourt where increasing quantities of dry gas, injected in previous years to maintain reservoir pressure, are now being produced. The average plant price received for condensate increased 15 cents to $2.89 per barrel as a result of a general price increase which became effective late in 1970. The average plant price received for LPG was $1.16 per barrel, unchanged from the previous year.

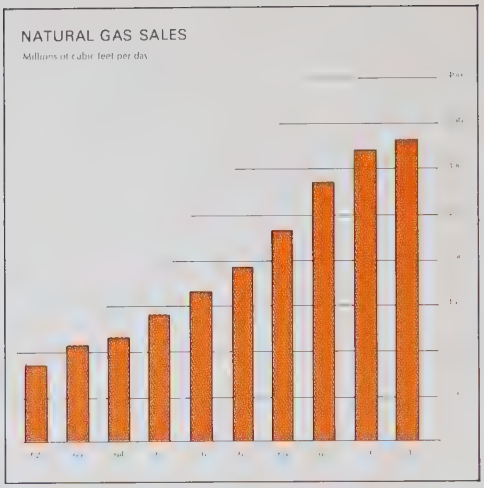
NATURAL GAS AND ASSOCIATED PRODUCTS — NET

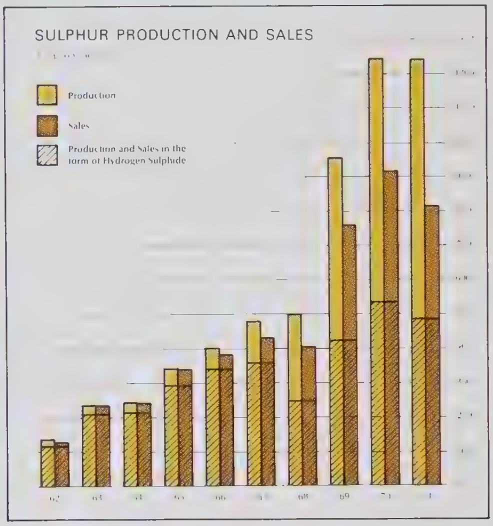
Locations	Natural Gas Sales (Million Cubic Feet Per Day) 1971	1970	Natural Gas Liquids Production: Condensate (Barrels Per Day) 1971	1970	LPG (Barrels Per Day) 1971	1970	Sulphur Production (Long Tons Per Day) 1971	1970
Brazeau	28.2	25.4	439	410	—	—	13	10
Caroline	14.2	13.3	432	423	346	339	5	5
Cessford Area	37.5	38.2	100	100	—	—	—	—
Clarke Lake	14.5	15.6	—	—	—	—	—	—
Edson	78.0	77.2	739	744	—	—	59	56
Harmattan Area	—	—	417	401	228	203	—	—
Kaybob 1	9.9	6.8	3,464	3,211	1,396	1,270	253	240
Kaybob 2	3.8	3.0	2,262	1,735	109	—	183	140
Lone Pine Creek	19.8	19.7	832	646	—	—	76	78
Pembina Area	6.2	7.3	23	30	147	102	—	—
Rimbey/Westerose	7.5	7.1	274	292	304	311	6	7
Sylvan Lake/Condor	9.3	10.7	173	214	334	359	—	—
Whitecourt	37.5	38.2	2,160	3,075	—	—	485	564
Other Locations	62.4	54.5	619	609	165	134	163	146
	328.8	317.0	11,934	11,890	3,029	2,718	1,243	1,246

Sulphur production averaged 1,243 long tons per day, essentially unchanged from 1970. Increased production at Kaybob South Plant No. 2 and at several other plants was offset by lower production resulting from plant problems at Whitecourt.

Sulphur sales declined by 11.2% to 814 long tons per day, equivalent to 65.4% of 1971 production. Most of the Company's sulphur production from the West Whitecourt plant is sold as produced under a contract whereby the purchaser takes delivery of the hydrogen sulphide contained in the natural gas produced from the field, converts it to elemental sulphur in its plant and pays the Company approximately one-half of the average plant price received for all Canadian sulphur sales in North American markets during the year. Sales under this contract averaged 468 long tons per day in 1971 compared with 536 long tons per day in 1970. The Company's other sulphur sales averaged 346 long tons per day, a decrease of 36 long tons per day or 9.5%. The average net price obtained for all sulphur sold during the year was $4.87 per ton, slightly above last year's price of $4.24 per ton.

The Company currently has interests in 46 gas processing plants, 11 of which it operates. Construction programs completed during the year included modifications at the Brazeau River and Edson plants and a new unit to recover a mixed LPG stream at Kaybob South Plant No. 2. The Kaybob facilities ultimately will add approximately 900 barrels per day to the Company's natural gas liquids production.





The Kaybob Plant complex at night.

Kaybob South Plant No. 3, an 18% owned partner-operated plant which was scheduled to commence operations in mid-1971, encountered construction difficulties which delayed start-up until early 1972 and has not yet reached design capacity. When the plant becomes fully operational it is expected to add about 7 million cubic feet of natural gas, 6,200 barrels of natural gas liquids and 350 long tons of sulphur to the Company's daily net production.

Other significant gas plant projects currently underway and scheduled for completion in 1972 or early 1973 consist of expansions at the Lone Pine Creek and Harmattan Elkton plants and enlargement of gas treating facilities at Clarke Lake. These projects, when fully operational, will add approximately 15 million cubic feet of natural gas, 150 barrels of natural gas liquids and 25 long tons of sulphur to the Company's daily net production. In addition, the commencement in December 1971, of gas sales from the main reservoir supplying Kaybob South Plant No. 1 has added approximately 5.6 million net cubic feet per day to the Company's gas sales.

A fractionation plant and associated transportation and storage facilities in which the Company will have an approximate 3,200 barrels per day net interest are under construction at Fort Saskatchewan. Although this plant will not increase the Company's overall production capacity it will upgrade revenues by separating a mixed LPG stream produced at the Kaybob No. 2 and No. 3 plants into finished propane, butane and condensate.

Propane tank car at a Company operated loading terminal.

Reserves — The Company's net remaining recoverable reserves at year end (after deducting all royalties and interests owned by others), as estimated by its reservoir engineering staff, are shown in the accompanying table. The estimated proved reserves include only such reserves as reasonably can be classified as proved in accordance with widely accepted American Petroleum Institute standards. Probable reserves include reserves which are substantially proved on undrilled tracts closely associated with proved reserves and for which geological control is sufficient to offer good indication of continuity of the producing horizon. Incremental reserves from enhanced recovery techniques are included in the probable category when the required facilities are installed and are transferred to the proved category only after the anticipated reservoir performance has been confirmed. Liquefied petroleum gases are not included in the reported reserves of natural gas liquids unless the facilities required for their extraction are in existence or are assured of construction. Heavy oil, such as in the Athabasca Tar Sands, has not been included.

During 1971 the Company experienced a slight decrease in its total proved and probable reserves as additions to reserves failed to offset production. Additions to crude oil and natural gas liquids reserves of 18.9 million barrels resulted from upward revisions based on updated performance data in a number of fields and from new wells drilled in 1971. Production of liquid hydrocarbons totalled 23.3 million barrels, exceeding reserve additions by 4.4 million barrels. Additions to natural gas reserves totalled 86 billion cubic feet, with production of 120 billion cubic feet exceeding additions by 34 billion cubic feet. Remaining sulphur reserves were 16,000 tons lower than at the end of 1970.

NET RESERVES
December 31, 1971

	Crude Oil (Barrels)	Natural Gas Liquids (Barrels)	Natural Gas (Million cubic feet)	Sulphur (Long tons)
Proved	263,023,000	101,201,000	2,878,000	8,751,000
Probable	21,634,000	3,286,000	299,000	1,152,000
Total	284,657,000	104,487,000	3,177,000	9,903,000


ARCTIC OCEAN
ALASKA
U.S.A.
BANKS ISLAND
MELVILLE I.
LOUGHEED I.
BATHURST I.
CORNWALLIS I.
PRINCE OF WALES I.
VICTORIA ISLAND
TUKTOYAKTUK
INUVIK
YUKON
NORMAN WELLS
WHITEHORSE
NORTHWEST TERRITORIES
YELLOWKNIFE
PACIFIC OCEAN
BRITISH COLUMBIA
FORT ST. JOHN
McMURRAY
ALBERTA
EDMONTON
SASKATCHEWAN
MANITOBA
VANCOUVER
CALGARY
SASKATOON
REGINA
WINNIPEG
U.S.A.


MAP SHOWING ACREAGE HOLDINGS
of
Hudson's Bay Oil and Gas Company Limited
at December 31, 1971
LEGEND
The areas within which the Company has substantial holdings of petroleum and natural gas rights are indicated by the red color.
The Company has the exclusive right until December 31, 1999 to acquire leases on all petroleum and natural gas rights owned by Hudson's Bay Company. This right covers approximately 4,500,000 acres of lands, most of which are distributed in a regular pattern - basically all or part of two one-square-mile sections in each 36-section township - in the areas covered by this light red tinting.
Sedimentary Basins
0
100
200
miles
GREENLAND
ESMERE
SLAND
LAND
BAFFIN ISLAND
SOUTHAMPTON I.
DSON
BAY
TARIO
QUEBEC
NEWFOUNDLAND
ANTICOSTI I.
ST. JOHN'S
ATLANTIC OCEAN
P.E.I.
CHARLOTTETOWN
NEW BRUNSWICK
FREDERICTON
NOVA SCOTIA
HALIFAX
QUEBEC
MONTREAL
OTTAWA
U.S.A.
TORONTO

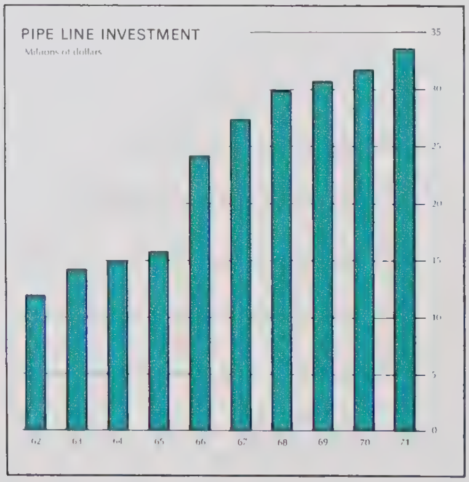
Supply and Transportation

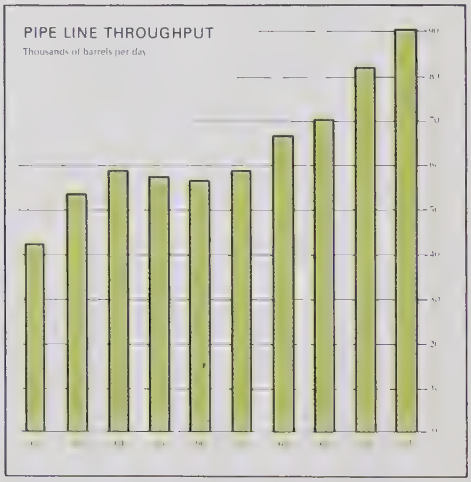
Pipe Line — During 1971 the Company's wholly-owned pipe line systems gathered and transported an average of 90,463 barrels per day of crude oil and natural gas liquids, 8,533 barrels per day or 10.4% above the previous year. Deliveries to connecting pipe lines serving the U.S. Rocky Mountain area and other mid-western states advanced by 20,050 barrels per day to 70,833 barrels per day. Revenue from pipe line operations grew more rapidly than volumes because of a larger proportion of long distance trunk line deliveries to connecting pipe lines serving the United States.

Expenditures for additions and extensions to the Company's pipe line system amounted to $2,093,000 during the year. The most significant feature of the 1971 construction program was the installation of two new pumping stations to increase the capacity of the 12-inch trunk line from Sundre to the United States border.

In addition to its wholly-owned pipe line operation, the Company has an approximate 16% ownership interest in Peace River Oil Pipe Line Co. Ltd. This producer-owned system operates extensive crude oil gathering and trunk line facilities serving producing areas northwest of Edmonton. During 1971 the Company received a $763,000 dividend from Peace River Oil Pipe Line Co. Ltd. representing a partial distribution of earnings since its last dividend payment in 1965.

The Company is a participant in Mackenzie Valley Pipe Line Research Limited, a group formed by 16 western Canadian producing and transportation companies to investigate the environmental and economic feasibility of a crude oil pipe line from northern Canada and Alaska to Edmonton through the Mackenzie Valley. These efforts will make it possible to thoroughly evaluate a pipe line project that would deliver Arctic oil to markets in Canada and the United States with a minimum of ecological disturbance.





Other Operations — Crude oil trading operations continued to show significant expansion during 1971 due to increased Alberta production and growth in sales to consumers in the U.S. Rocky Mountain area. The volume of crude and condensate handled in this operation averaged 112,100 barrels per day, an increase of 26,700 barrels per day or 31.3% from the previous year.

LPG marketing activities also showed continued growth in 1971. Propane sales increased concurrently with Company production while butane sales rose somewhat more rapidly due to increased demand at refineries served in the U.S. Rocky Mountain area. LPG marketing will be enhanced through the flexibility provided by the cavern storage facilities under construction in connection with the Fort Saskatchewan fractionation project mentioned earlier.

Blue Flame Propane Ltd., a wholly-owned subsidiary, now has seventeen retail branches and six consignee operations in western Canada. Total sales volumes rose 25.3% in 1971 to 12.4 million gallons. Because of declining profit margins however, earnings did not advance in proportion to the growth in sales.

Pipe line shipments are controlled from this automated system in the Calgary office.

Environmental Conservation

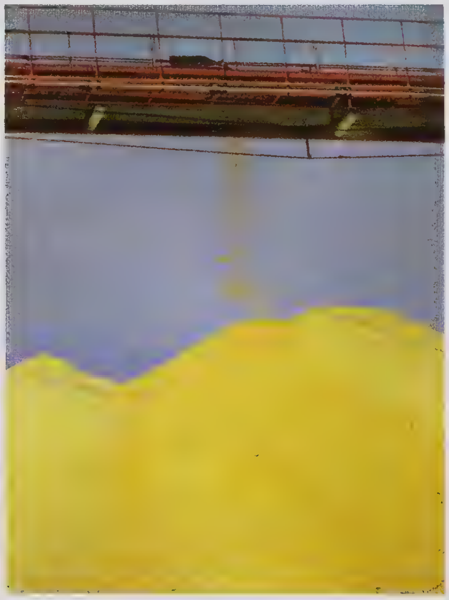
Further progress was made during the year in the Company's continuing effort to maintain environmental standards in the areas in which it operates. Total capital expenditures for facilities to control pollution amounted to $1.7 million, and a similar amount will be spent in 1972.

The Company strengthened its environmental conservation program during the year by establishing an Environmental Conservation Department. This Department coordinates Company policies for the responsible use of the environment in cooperation with industry and government agencies involved in pollution control.

One of the major environmental problems faced by the petroleum industry is the recovery of sulphur during the processing of sour natural gas. Significant progress was made in solving this problem during the year. Improvements in plant design, operations and equipment at the Edson gas plant have reduced stack emissions of sulphur dioxide to a level well below standards set by regulating authorities. These new techniques are now being applied at Kaybob, Brazeau River and Lone Pine Creek. A new process to improve sulphur recovery even further was successfully pilot-tested at the Company-operated Lone Pine Creek plant and a number of other new processes have been studied. Full-scale installations are being evaluated for several gas processing plants to facilitate meeting even stricter sulphur recovery regulations scheduled to become effective in 1975.

During the year equipment was installed at Kaybob South Plants No. 1 and 2 to produce sulphur in a slate-like form. This process has virtually eliminated sulphur dust pollution both in the Kaybob area and at Vancouver where the sulphur is transferred from rail cars to ships or stockpiles.

The Company follows a policy of operating its installations in a manner to achieve maximum levels of environmental protection and participates actively in a number of industry organizations that work closely with Federal and Provincial bodies concerned with the environment. Plans have been developed to handle emergency situations such as accidental oil spills with all the necessary resources of men and equipment. The Company also supports a number of research programs oriented to the preservation of the environment.



Storage area for "slated" sulphur produced at the Kaybob South plants.

Employees

The Company and its subsidiaries had a total of 1,076 employees at year end, 33 more than at the beginning of the year. The total cost of salaries, wages and employee benefits reached $12,375,000, up 15.0%.

During the year, the Company revised the terms of its major benefits plans in order to provide a more comprehensive and fully competitive benefits program for its employees. The retirement program was revised to provide for larger pension benefits and the life and disability insurance programs were improved, all at reduced costs to employees. The Company also increased its contribution rates to the Thrift Plan, which is designed to encourage employee savings through proportional Company contributions. At year end the assets of the Thrift Plan included 5,191 preferred shares and 34,089 common shares of the Company's capital stock purchased on instructions of employees for their accounts.

Lower left, geologist examining rock cuttings obtained from a drilling well.

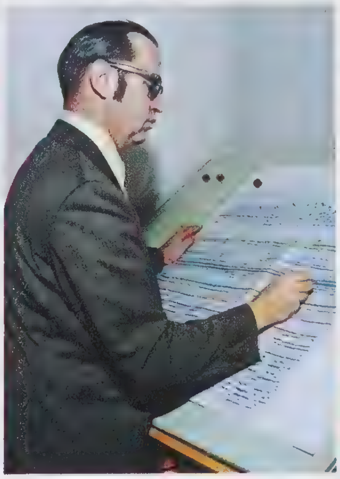
Centre, examining seismic records for indications of potential hydrocarbon reservoirs.

Lower right, tracing meter records to calculate volumes of natural gas produced.

The Company continued its recruiting program at a number of major universities and technical schools in Canada to assist in meeting its requirements for professional and technical staff. It also sponsored and supported programs, both on the job and through facilities available at educational institutions, to develop the technical, professional and managerial skills of its employees. In addition, financial assistance was provided to 98 employees who successfully completed job-related evening and correspondence courses.

Through its Financial Aid to Education program, the Company contributed a total of $102,000 in support of higher education by providing funds for capital projects, grants, awards and scholarships. A total of 17 university scholarships were awarded to employees' sons and daughters and another 5 scholarships were awarded to outstanding applicants at Canadian universities.

Despite the increasing size and complexity of its operating facilities, the Company has achieved an excellent record of accident prevention. Continuing emphasis is placed on educational programs designed to instill a high degree of safety consciousness in each employee. During the year, six Company-operated gas plants received Canadian Natural Gas Processors Association Safety Awards for operating twelve consecutive months without a lost time accident.



Financial Review

Net earnings in 1971 were $23,155,000, an increase of 14.8% over 1970 earnings of $20,170,000 and, after providing for preferred dividends, amounted to $1.18 per common share. Funds generated from operations advanced 14.7% to $51,180,000 or $2.72 per common share.

A total of 719,976 of the Company's common shares are reserved for potential conversion of the 599,980 outstanding convertible preferred shares. If the potential conversion had been fully effected at the beginning of 1971, earnings would have been $1.22 per common share and funds generated from operations would have been $2.69 per common share.

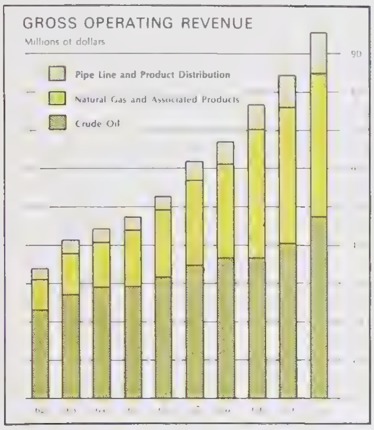
Dividends declared for the year totalled $11,561,000 compared with $10,647,000 in 1970. On the common shares, a dividend of 25 cents was declared in June and 30 cents in December — a total of 55 cents compared with 50 cents in the prior year. Regular quarterly dividends totalling $2.50 per share were declared on the preferred shares.

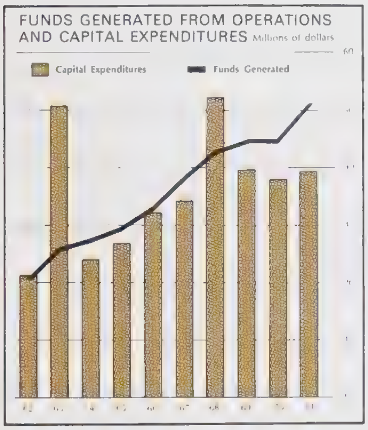
Gross operating revenues in 1971 were $95,307,000, an increase of $11,117,000 or 13.2%. The accompanying table shows the major sources of operating revenues and changes from the prior year. The reasons for these changes have been provided in earlier sections of this report. Income from investments and other miscellaneous sources declined to $2,665,000 from $4,154,000 in the prior year, primarily because of lower yields on smaller holdings of short term investments.

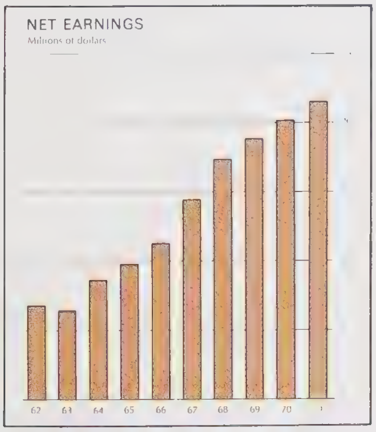
Total expenses for the year, before income taxes, amounted to $62,019,000, up $5,959,000 or 10.6%. These expenses include $34,018,000 of cash operating and exploration expenses, up 17.3%; $23,338,000 of non-cash charges, up 8.6%; and $4,663,000 of interest and other expenses, down 16.3%.

GROSS OPERATING REVENUES

Category	Amount in 1971	Percentage of Total	Amount in 1970	Percentage of Total	Increase (Decrease) from 1970 Amount	Increase (Decrease) from 1970 Percent
Crude Oil	$47,501,000	49.9	$40,416,000	48.0	$ 7,085,000	17.5
Natural Gas Liquids	13,854,000	14.5	12,926,000	15.4	928,000	7.2
Natural Gas	18,767,000	19.7	17.938,000	21.3	829,000	4.6
Sulphur	1,446,000	1.5	1,421,000	1.7	25,000	1.8
Processing Non-Owned Gas	2,783,000	2.9	3,061,000	3.6	(278,000)	(9.1)
Pipe Line and Product Distribution	10,956,000	11.5	8,428,000	10.0	2,528,000	30.0
Total	$95,307,000	100.0	$84,190,000	100.0	$11,117,000	13.2







The main cause of the increased cash expenses was a $3,251,000 or 20.8% advance in production expenses which resulted from costs associated with new facilities, larger production volumes and inflationary escalation in material and labour costs. Exploration expenses increased by $651,000, mainly due to higher expenditures on geophysical projects. Pipe line and product distribution costs were up by $974,000, most of which resulted from a non-recurring loss on marine transportation operations associated with the Company's sulphur sales program.

Non-cash charges for depletion, depreciation, amortization and dry holes totalled $23,338,000, up $1,854,000 or 8.6%. A $561,000 increase in the provision for depletion primarily reflects higher production volumes while an additional $482,000 of depreciation resulted from new investment in gas plants and other production facilities. Dry hole charges were up $512,000 due in part to inclusion of the costs of three deep exploratory wells, located in the Gold Creek area of west-central Alberta, that were commenced in 1970 but not completed until early in 1971.

The total provision required for income taxes was $12,798,000 compared with $12,114,000 in 1970. Income taxes did not increase in proportion to pre-tax earnings because of the reduction in corporate tax rates which became effective on July 1, 1971.

Capital expenditures totalled $39,359,000, up $1,995,000 or 5.3% over the amount spent in 1970. Increased expenditures for production and pipe line facilities were partially offset by reduced outlays for acreage acquisitions.

Funds generated from operations and other internal sources were sufficient to provide 98% of the amounts used during the year for capital expenditures, dividends and required debt retirement. In addition to its required debt retirement, the Company elected to prepay its term bank loan and some of the future sinking fund requirements on its first mortgage bond issues. As a result long term debt was reduced to $68,417,000 and no payments will be required on this debt during 1972. At year end the Company retained a strong working capital position of $15,778,000.

At December 31, 1971 common and preferred shareholders' equity totalled $160,184,000. Of the 18,294,068 common shares outstanding, Continental Oil Company holds 54.9%, Hudson's Bay Company holds 21.9%, and 23.2% is held by 9,715 public shareholders. Geographically, 67.9% of the publicly owned common shares are in Canada, 27.1% are in the United States, 4.7% are in the United Kingdom and 0.3% are in other countries. The 599,980 convertible preferred shares outstanding are held by 2.593 public shareholders, with 97% of the stock held by Canadian residents. The conversion and redemption features of these shares are described in Note 7 to the financial statements and should be reviewed by preferred shareholders as the conversion rate will change on October 15, 1972. The Company will send a reminder to all preferred shareholders at an appropriate time with respect to this change in conversion rate.

Consolidated Balance Sheet - December 31, 1971 and 1970

Assets

	1971	1970
CURRENT ASSETS		
Cash	$ 1,565,000	$ 1,691,000
Short term investments at cost, which approximates market	13,459,000	25,056,000
Accounts receivable (Note 5)	27,023,000	26,538,000
Inventories		
Products at lower of average cost or realizable value	3,472,000	3,496,000
Materials and supplies at or below average cost	1,197,000	1,459,000
	46,716,000	58,240,000
PROPERTY, PLANT AND EQUIPMENT (Notes 1 and 2)		
At cost	428,624,000	398,479,000
Less: Accumulated depreciation, depletion and amortization	149,162,000	133,376,000
	279,462,000	265,103,000
OTHER ASSETS		
Investments in non-controlled companies at cost	1,514,000	1,571,000
Unamortized bond discount and expense	672,000	749,000
Unamortized goodwill	217,000	259,000
Deposits, deferred charges and miscellaneous assets at cost	2,164,000	2,835,000
	4,567,000	5,414,000
	$330,745,000	$328,757,000

Approved on behalf of the Board:

D. G. Jones, DIRECTOR

L. R. Olson, DIRECTOR

Liabilities and Shareholders' Equity

	1971	1970
CURRENT LIABILITIES		
Accounts payable and accrued liabilities (Note 5)	$ 23,821,000	$ 22,977,000
Dividends payable (Note 5)	5,862,000	4,949,000
Income and other taxes payable	1,255,000	6,653,000
Long term debt due within one year (Note 6)	—	4,175,000
	30,938,000	38,754,000
LONG TERM DEBT (Note 6)	68,417,000	75,334,000
DEFERRED CREDITS		
Advances received on future natural gas sales	6,443,000	6,538,000
Other	1,334,000	1,437,000
	7,777,000	7,975,000
DEFERRED INCOME TAXES (Note 4)	63,429,000	58,104,000
SHAREHOLDERS' EQUITY		
Capital stock (Note 7)		
Authorized		
Preferred — $50 par value — 1,500,000 shares		
Common — $2.50 par value — 25,000,000 shares		
Issued and outstanding		
5% Cumulative Redeemable Convertible Preferred Shares Series A — 599,980 shares (600,000 shares in 1970)	29,999,000	30,000,000
Common — 18,294,068 shares (18,294,044 shares in 1970)	45,735,000	45,735,000
Contributed surplus (Note 7)	21,096,000	21,095,000
Retained earnings	63,354,000	51,760,000
	160,184,000	148,590,000
	$330,745,000	$328,757,000

See Notes To The Consolidated Financial Statements

Consolidated Statement of Earnings

Years Ended December 31, 1971 and 1970

	1971	1970
REVENUES		
Gross operating revenues	$95,307,000	$84,190,000
Investment and other income	2,665,000	4,154,000
	97,972,000	88,344,000
EXPENSES		
Exploration	8,972,000	8,321,000
Production	18,880,000	15,629,000
Pipe line and product distribution	3,455,000	2,481,000
General administrative	2,711,000	2,573,000
Depletion	6,071,000	5,510,000
Depreciation	8,564,000	8,082,000
Amortization of undeveloped oil and gas rights	3,586,000	3,287,000
Dry holes and abandonments	5,117,000	4,605,000
Interest (Note 6)	4,539,000	5,478,000
Other	124,000	94,000
	62,019,000	56,060,000
NET EARNINGS BEFORE INCOME TAXES	35,953,000	32,284,000
INCOME TAXES (Note 4)		
Current	7,473,000	7,854,000
Deferred	5,325,000	4,260,000
	12,798,000	12,114,000
NET EARNINGS (Note 1)	$23,155,000	$20,170,000
NET EARNINGS PER COMMON SHARE (Note 8)	$1.18	$1.02

Consolidated Statement of Retained Earnings

Years Ended December 31, 1971 and 1970

	1971	1970
Retained earnings — January 1	$51,760,000	$42,237,000
Net earnings	23,155,000	20,170,000
	74,915,000	62,407,000
Dividends Declared		
Preferred shares	1,500,000	1,500,000
Common shares	10,061,000	9,147,000
	11,561,000	10,647,000
Retained Earnings — December 31	$63,354,000	$51,760,000

See Notes To The Consolidated Financial Statements

Consolidated Statement of Sources and Uses of Funds

Years Ended December 31, 1971 and 1970

	1971	1970
SOURCES OF FUNDS		
Net earnings	$ 23,155,000	$ 20,170,000
Add items which did not require an outlay of funds:		
Depreciation, depletion and amortization	18,221,000	16,879,000
Dry holes and abandonments	5,117,000	4,605,000
Deferred income taxes	5,325,000	4,260,000
Other — net	(638,000)	(1,307,000)
Funds generated from operations	51,180,000	44,607,000
Sale of properties and investments	1,778,000	2,562,000
Advances received on future natural gas sales	55,000	1,481,000
Miscellaneous — net	1,116,000	1,166,000
TOTAL FUNDS AVAILABLE	$ 54,129,000	$ 49,816,000
USES OF FUNDS		
Expenditures for property, plant and equipment	$ 39,359,000	$ 37,364,000
Reduction of long term debt	6,917,000	7,727,000
Dividends declared	11,561,000	10,647,000
TOTAL FUNDS USED	$ 57,837,000	$ 55,738,000
RESULTING INCREASE (DECREASE)		
In cash and short term investments	$ (11,723,000)	$ (6,487,000)
In other working capital items	8,015,000	565,000
IN TOTAL WORKING CAPITAL	$ (3,708,000)	$ (5,922,000)
Working Capital — December 31	$ 15,778,000	$ 19,486,000

See Notes To The Consolidated Financial Statements

Auditors' Report to the Shareholders

We have examined the consolidated balance sheet of Hudson's Bay Oil and Gas Company Limited and subsidiary companies as of December 31, 1971 and the consolidated statements of earnings, retained earnings and sources and uses of funds for the year then ended. Our examination included a general review of the accounting procedures and such tests of accounting records and other supporting evidence as we considered necessary in the circumstances.

In our opinion, these consolidated financial statements present fairly the financial position of the Company and subsidiary companies at December 31, 1971 and the results of their operations and the sources and uses of their funds for the year then ended, in accordance with generally accepted accounting principles applied on a basis consistent with that of the preceding year.

Peat, Marwick, Mitchell & Co.

Chartered Accountants

Calgary, Alberta
January 28, 1972

Notes to the Consolidated Financial Statements

NOTE 1 ACCOUNTING POLICIES

The consolidated financial statements include the accounts of Hudson's Bay Oil and Gas Company Limited and its subsidiary companies, each of which is wholly owned. Where the purchase price of shares of subsidiaries exceeded their net book values, the excess has been allocated to the related assets acquired and additional depreciation, depletion and amortization has been provided accordingly.

Exploration expenses are charged against earnings as incurred.

Costs of oil and gas rights are capitalized when acquired. A regular charge is made to earnings for amortization of undeveloped oil and gas rights and when such rights are surrendered their cost is charged against the accumulated amortization. When undeveloped rights are proven to be productive the original cost is transferred to the developed oil and gas rights account and charged to earnings by an annual provision for depletion calculated on the unit of production method.

All costs of drilling wells are initially capitalized. If, on completion, a well is not capable of commercial production its cost is immediately written off. The costs of successful wells, other than equipment costs, are depleted on the unit of production method in the same manner as the cost of developed oil and gas rights.

Plant, pipe line and equipment costs are depreciated on the straight line method at rates estimated to amortize the costs over the useful lives of the assets, except that certain pipe line assets are depreciated on the unit of throughput method.

The Company follows the tax allocation basis of accounting with respect to all timing differences between net earnings and taxable income as more fully explained in Note 4.

NOTE 2 PROPERTY, PLANT AND EQUIPMENT

	Assets at Cost	Accumulated Depreciation	Accumulated Depletion	Accumulated Amortization	Net
Undeveloped oil and gas rights	$ 51,608,000	$ —	$ —	$10,032,000	$ 41,576,000
Developed oil and gas rights	33,476,000	—	13,407,000	—	20,069,000
Oil and gas rights on Hudson's Bay Company lands	1,000	—	—	—	1,000
Wells and related facilities	199,256,000	34,011,000	63,072,000	—	102,173,000
Plants and related facilities	102,534,000	17,927,000	—	—	84,607,000
Pipe line and product distribution facilities	37,977,000	9,195,000	—	—	28,782,000
Other	3,772,000	1,518,000	—	—	2,254,000
Total — December 31, 1971	$428,624,000	$62,651,000	$76,479,000	$10,032,000	$279,462,000
Total — December 31, 1970	$398,479,000	$55,165,000	$70,577,000	$ 7,634,000	$265,103,000

Pursuant to an agreement the Company has an exclusive right until December 31, 1999 to lease any or all of the petroleum and natural gas rights owned by Hudson's Bay Company. The exercise of this right requires no bonus payment. The Hudson's Bay Company lands subject to this agreement totalled 4,504,000 acres at December 31, 1971, primarily in the Provinces of Alberta, Saskatchewan and Manitoba. A nominal value of $1,000 has been assigned to these rights.

NOTE 3 REMUNERATION OF DIRECTORS AND OFFICERS

Aggregate direct remuneration paid or payable in 1971 by the Company and its subsidiaries to the Company's directors and officers amounted to $33,729 and $338,913 respectively. During the year there were a total of 13 directors and 9 officers of whom 2 served in both capacities.

NOTE 4 INCOME TAXES

In determining taxable income under the provisions of the Income Tax Act and Regulations, the Company and each of its subsidiaries is permitted to deduct currently: acquisition costs of petroleum and natural gas rights; costs of drilling successful wells; and capital cost allowances greater than depreciation reported in the accounts. In determining net earnings for accounting purposes these costs are charged against earnings in a systematic manner over the estimated useful lives of the related facilities. Because costs claimed in the determination of income taxes payable have exceeded the related amounts charged in the determination of net earnings, an amount equivalent to the resultant reduction in current income taxes payable has been charged to earnings and credited to Deferred Income Taxes. The purpose of the tax allocation basis of accounting is to provide a proper matching of income tax expense with pre-tax earnings.

NOTE 5 AMOUNTS OWING TO AND FROM AFFILIATED COMPANIES

Accounts receivable include $6,282,000 due from Continental Oil Company and its subsidiaries. Accounts payable include $79,000 due to Continental Oil Company and $118,000 due to Hudson's Bay Company. The foregoing balances resulted from transactions in the normal course of business. Dividends payable include $2,711,000 due to Continental Oil Company and $1,203,000 due to Hudson's Bay Company.

NOTE 6 LONG TERM DEBT

	1971	1970
First Mortgage Sinking Fund Bonds		
4% Series A, due May 1, 1975 — remaining sinking fund requirements — $900,000 in 1974 and $10,000,000 at maturity	$10,900,000	$12,705,000
5% Series B, due October 1, 1971	—	50 000
5¾% Series C, due August 1, 1977 — remaining sinking fund requirements — $129,000 in 1974, $160,000 per annum 1975 and 1976 and $100,000 at maturity	549,000	1,025,000
5½% Series D, due June 15, 1983 — remaining sinking fund requirements — $762,000 in 1973, $1,500,000 per annum 1974 to 1982 and $7,500,000 at maturity	21,762,000	23,853,000
7% Series E, due January 3, 1987 — remaining sinking fund requirements — $497,000 in 1974, $600,000 per annum 1975 to 1987	8,297,000	8,967,000
7.85% Series F, due April 15, 1994 (U.S. $25,000,000 issued and pledged to secure payment of the 7.85% Collateral Trust Bonds due 1994)	—	—
	41,508,000	46,600,000
Collateral Trust Bonds		
7.85% Collateral Trust Bonds due April 15, 1994 — sinking fund requirements U.S. $1,250,000 per annum 1979 to 1993 and U.S. $6,250,000 at maturity. (U.S. $25,000,000 recorded at exchange rate in effect at date of issue)	26,909,000	26,909,000
Term Loan		
Secured by assignment of hydrocarbon reserves. Interest at prime bank rate for production loans	—	6,000,000
	68,417,000	79,509,000
Less long term debt due within one year	—	4,175,000
	$68,417,000	$75,334,000

The aggregate payments of principal required on the foregoing long term debt in each of the next five years are as follows: NIL in 1972; $762,000 in 1973; $3,026,000 in 1974; $12,260,000 in 1975 and $2,260,000 in 1976.

Interest expense of $4,539,000 includes interest of $4,353,000 on long term debt described in the above table; and other interest charges of $186,000.

NOTE 7 CAPITAL STOCK

The Preferred Shares Series A are redeemable at the option of the Company from October 15, 1972 through October 14, 1977 at $53.50 and thereafter at $51.00. At the option of the holder each Preferred Share Series A may be converted, subject to adjustment under certain circumstances, into one and one-fifth Common Shares at any time on or before October 15, 1972 or thereafter may be converted into one Common Share on or before October 15, 1977 or such earlier date as may result from notice of redemption of the shares. During the year, 24 Common Shares were issued on conversion of 20 of the 5% Cumulative Redeemable Convertible Preferred Shares Series A. The excess of the par value of the Preferred Shares Series A converted over the par value of the Common Shares issued has been credited to Contributed Surplus.

At December 31, 1971 there were 719,976 Common Shares reserved for issue upon exercise of the rights of conversion attaching to the Preferred Shares Series A, being the maximum number of Common Shares that would be issued if all the Preferred Shares Series A were converted during the first conversion period.

NOTE 8 NET EARNINGS PER COMMON SHARE

Net earnings per common share are based on the weighted average number of Common Shares outstanding and are after dividend requirements on the 5% Cumulative Redeemable Convertible Preferred Shares Series A. If all the Preferred Shares Series A had been converted to Common Shares, there would have been no dilution in net earnings per Common Share.

NOTE 9 RETIREMENT PLAN

The Company has a contributory retirement plan which is open to all permanent employees. At June 30, 1971, the date of the last actuarial evaluation, the assets of the retirement plan exceeded the liabilities for retirement benefits accrued to that date.

NOTE 10 CONTINGENT LIABILITY

The Company has guaranteed the payment of principal (amounting to $2,974,000 at December 31, 1971) and interest on certain outstanding debentures of a pipe line company in which it has a share ownership.

Hudson's Bay Oil and Gas Company Limited

Incorporated under the Laws of Canada

BOARD OF DIRECTORS

A. W. TARKINGTON, *Chairman, New York, Director and Consultant, Continental Oil Company*

J. R. MURRAY, *Vice-Chairman, Winnipeg, Managing Director of Hudson's Bay Company*

T. N. BEAUPRÉ, *Montreal, Chairman of the Board of Directors and President of Domtar Limited and Director of Hudson's Bay Company*

H. W. BLAUVELT, *New York, President, Conoco Chemicals Division, Continental Oil Company and Director of Continental Oil Company*

G. H. BLUMENAUER, *Hamilton, Chairman of the Board of Directors and President of Otis Elevator Company Limited*

W. E. GLENN, *Houston, President of Western Hemisphere Petroleum Division and Director of Continental Oil Company*

D. C. JONES, *Calgary, President of the Company*

HERBERT H. LANK, *Montreal, Director of Du Pont of Canada Limited*

A. M. MCGAVIN, *Vancouver, President of McGavin ToastMaster Limited and Director of Hudson's Bay Company*

JOHN G. MCLEAN, *New York, President and Chief Executive Officer and Director of Continental Oil Company*

S. G. OLSON, *Calgary, Executive Vice-President of the Company*

J. S. ROYDS, *New York, Senior Vice-President, World-Wide Coordinator of Exploration and Director of Continental Oil Company*

OFFICERS

D. C. JONES, *President*

S. G. OLSON, *Executive Vice-President*

K. H. BURGIS, *Corporate Vice-President*

R. J. HAMILTON, *Vice-President, Exploration*

R. F. HASKAYNE, *Financial Vice-President and Treasurer*

G. J. MAIER, *Vice-President, Production*

G. W. BENNETT, *Controller*

W. E. SELBY, *Secretary*

F. J. MAIR, *Assistant Secretary*

Ten Year Financial Review (1)

	1971	1970
GROSS OPERATING REVENUES		
Crude Oil	$ 47,501	40,416
Natural Gas Liquids	$ 13,854	12,926
Natural Gas	$ 18,767	17,938
Sulphur	$ 1,446	1,421
Processing Non-owned Gas	$ 2,783	3,061
Pipe Line and Product Distribution	$ 10,956	8,428
TOTAL	$ 95,307	84,190
EARNINGS AND DIVIDENDS		
Net Earnings Before Income Taxes	$ 35,953	32,284
Income Taxes — Current	$ 7,473	7,854
— Deferred	$ 5,325	4,260
Net Earnings	$ 23,155	20,170
Per Common Share	$ 1.18	1.02
Funds Generated from Operations	$ 51,180	44,607
Per Common Share	$ 2.72	2.36
Total Dividends Declared	$ 11,561	10,647
Per Common Share	$ .55	.50
Per Preferred Share	$ 2.50	2.50
FINANCIAL POSITION		
Working Capital	$ 15,778	19,486
Property Plant and Equipment — Net	$279,462	265,103
Long Term Debt	$ 68,417	75,334
Deferred Income Taxes	$ 63,429	58,104
Shareholders' Equity	$160,184	148,590
Number of Preferred Shares Outstanding (thousands)	600	600
Number of Common Shares Outstanding (thousands)	18,294	18,294
CAPITAL EXPENDITURES AND EXPLORATION EXPENSES		
Petroleum Exploration Expense	$ 8,526	7,981
Minerals Exploration Expense	$ 446	340
Total Exploration Expense	$ 8,972	8,321
Acquisition of Oil and Gas Rights	$ 4,067	5,658
Exploratory Drilling	$ 5,182	5,286
Total Exploration Capital Expenditures	$ 9,249	10,944
Development Drilling and Production Facilities	$ 10,436	8,821
Plants and Related Facilities	$ 15,524	15,462
Pipe Line and Product Distribution Facilities	$ 2,802	1,680
Other	$ 1,348	457
Total Capital Expenditures	$ 39,359	37,364
TOTAL CAPITAL EXPENDITURES AND EXPLORATION EXPENSE	$ 48,331	45,685
TOTAL EXPLORATION CAPITAL EXPENDITURES AND EXPENSE	$ 18,221	19,265
EMPLOYEES AND SHAREHOLDERS		
Number of Preferred Shareholders	2,593	2,625
Number of Common Shareholders	9,717	9,751
Number of Employees	1,076	1,043

(1) With the exception of per share figures, dollar amounts are in thousands.

(2) Exclusive of special credit of $856,000.

(3) Includes $27,866,000 acquisition costs of Consolidated Mic Mac Oils Ltd. and Security Freehold Petroleums Limited.

Ten Year Operating Review

	1971	1970
CRUDE OIL AND NATURAL GAS LIQUIDS PRODUCTION — NET (Barrels per day)		
Crude Oil — Alberta	38,313	34,343
British Columbia	5,765	6,408
Saskatchewan	4,751	4,791
Manitoba	17	18
	48,846	45,560
Condensate	11,934	11,890
LPG	3,029	2,718
TOTAL CRUDE OIL AND NATURAL GAS LIQUIDS	63,809	60,168
NATURAL GAS SALES — NET (Millions of cubic feet per day)	328.8	317.0
SULPHUR (Net long tons per day) — Production	1,243	1,246
Sales	814	917
PIPE LINE		
Throughput (Barrels per day)	90,463	81,930
Miles of Trunk Line	420	420
Miles of Gathering Facilities	450	450
WELL DATA		
TOTAL GROSS WELLS COMPLETED	199	225
NET EXPLORATORY WELLS COMPLETED		
Oil	5.5	2.7
Gas	3.7	8.1
Dry	23.0	24.0
TOTAL	32.2	34.8
NET DEVELOPMENT WELLS COMPLETED		
Oil	21.8	23.8
Gas	10.6	13.4
Dry	9.5	12.3
TOTAL	41.9	49.5
NET WELLS CAPABLE OF PRODUCTION		
Oil Wells	1,013.3	1,010.7
Gas Wells	256.9	241.9
TOTAL	1,270.2	1,252.6
OIL AND GAS RIGHTS — NET (Thousands of acres)		
Undeveloped		
British Columbia	1,459	2,634
Alberta	3,795	3,812
Saskatchewan	4,431	4,511
Manitoba	789	789
Northwest Territories (including Arctic Islands and Baffin Offshore)	9,697	5,216
East Coast	7,942	5,195
TOTAL UNDEVELOPED	28,113	22,157
Developed	544	534
TOTAL	28,657	22,691

1969	1968	1967	1966	1965	1964	1963	1962
31,832	31,804	29,386	25,856	25,456	26,389	25,057	22,167
6,100	5,710	5,693	5,247	3,083	2,220	2,216	1,354
4,527	4,919	5,259	4,826	4,582	4,294	3,799	3,265
19	19	16	14	13	10	10	4
42,478	42,452	40,354	35,943	33,134	32,913	31,082	26,790
10,058	6,091	6,282	5,944	5,303	4,877	4,373	3,349
1,890	972	658	569	453	346	231	215
54,426	49,515	47,294	42,456	38,890	38,136	35,686	30,354
281.7	233.3	196.7	169.5	138.2	116.6	104.6	82.1
955	500	481	404	344	246	238	140
760	406	433	386	343	245	237	132
70,135	66,578	58,812	56,123	57,502	58,817	53,724	42,678
420	420	420	391	200	200	200	187
425	423	366	334	314	297	266	211
244	166	203	222	195	225	249	164
4.0	4.8	19.9	9.5	7.2	5.0	5.4	2.8
4.9	3.9	8.0	9.0	4.2	7.7	8.1	2.3
43.1	29.5	33.3	40.0	28.9	28.9	22.1	16.8
52.0	38.2	61.2	58.5	40.3	41.6	35.6	21.9
31.5	19.3	30.0	34.8	38.4	60.2	66.3	65.1
19.8	16.2	17.1	9.8	10.3	8.0	8.7	7.1
6.7	6.9	8.8	12.1	11.0	9.8	14.9	13.8
58.0	42.4	55.9	56.7	59.7	78.0	89.9	86.0
1,010.3	978.7	992.2	957.1	919.7	917.2	877.0	754.6
226.5	201.1	189.7	166.8	152.7	136.2	125.3	97.4
1,236.8	1,179.8	1,181.9	1,123.9	1,072.4	1,053.4	1,002.3	852.0
2,391	1,078	980	1,025	1,203	1,161	1,952	2,000
4,005	4,610	5,520	6,434	6,699	5,745	5,601	4,367
4,742	4,751	4,996	5,196	3,931	2,960	2,980	2,655
789	789	789	789	789	792	792	703
5,197	3,571	2,293	2,033	1,871	1,027	1,461	1,697
5,195	5,405	4,583	9,167	9,167	—	—	—
22,319	20,204	19,161	24,644	23,660	11,685	12,786	11,422
512	472	405	383	356	347	321	274
22,831	20,676	19,566	25,027	24,016	12,032	13,107	11,696

1969	1968	1967	1966	1965	1964	1963	1962
36,580	36,671	34,848	31,358	28,867	28,879	27,112	22,987
10,593	6,490	6,314	5,826	5,196	4,709	4,312	3,234
15,742	12,445	10,483	9,009	7,339	5,954	5,218	3,895
4,272	4,004	3,641	1,527	1,428	430	411	241
2,659	1,381	1,389	1,197	820	593	666	414
6,649	5,893	5,013	3,565	3,567	3,677	3,305	2,825
76,495	66,884	61,688	52,482	47,217	44,242	41,024	33,596
29,390	26,810	22,139	17,371	15,355	13,803	12,331	10,166
2,360	20	—	—	—	—	—	—
8,147	9,389	7,623	6,055	5,527	5,138	5,868	3,336
18,883	17,401	14,516	11,316	9,828	8,665	6,463	6,830 [2]
.95	.87	.77	.62	.54	.47	.35	.38
44,794	42,751	38,277	32,813	29,444	27,372	25,760	21,106
2.37	2.25	2.07	1.79	1.61	1.50	1.41	1.19
10,647	10,647	9,522	7,318	7,318	6,403	5,488	5,324
.50	.50	.50	.40	.40	.35	.30	.30
2.50	2.50	.625	—	—	—	—	—
25,408	3,824	29,367	1,730	(3,456)	(3,750)	(213)	(6,501)
251,019	231,828	198,265	181,225	165,394	153,889	144,295	106,861
83,061	62,593	69,743	66,653	49,800	51,000	52,570	23,539
53,844	45,697	36,308	28,685	22,630	17,103	11,965	6,097
139,067	130,831	124,077	89,615	85,617	83,107	80,845	71,382
600	600	600	—	—	—	—	—
18,294	18,294	18,294	18,294	18,294	18,294	18,294	17,745
8,890	8,257	7,436	6,176	5,628	4,794	4,460	4,562
548	82	—	—	—	—	—	—
9,438	8,339	7,436	6,176	5,628	4,794	4,460	4,562
14,171	5,766	1,493	3,775	7,847	3,037	28,534	4,320
4,031	5,303	8,053	5,873	4,535	4,191	4,663	3,224
18,202	11,069	9,546	9,648	12,382	7,228	33,197	7,544
10,893	10,622	13,100	8,891	7,618	10,433	12,396	8,287
8,663	26,428	6,049	4,788	5,861	5,350	2,812	1,899
1,496	3,305	5,085	8,536	847	812	2,341	3,315
425	932	536	354	362	358	161	245
39,679	52,356	34,316	32,217	27,070	24,181	50,907 [3]	21,290
49,117	60,695	41,752	38,393	32,698	28,975	55,367	25,852
27,640	19,408	16,982	15,824	18,010	12,022	37,657	12,106
2,677	2,851	3,312	—	—	—	—	—
8,688	8,864	9,254	9,859	10,674	11,548	12,526	11,038
938	849	738	613	574	506	475	454

Hudson's Bay Oil and Gas Company Limited

HEAD OFFICE

320 Seventh Avenue South West, Calgary 2, Alberta

SUBSIDIARY COMPANIES (All Wholly-Owned)

AURORA PIPE LINE COMPANY, *incorporated by Special Act of the Parliament of Canada*

BLUE FLAME PROPANE LTD., *incorporated under the Laws of the Province of Alberta*

HBOG MINING LIMITED, *incorporated under the Laws of the Province of Ontario*

MIC MAC OILS (1963) LTD., *incorporated under the Laws of the Province of Alberta*

RANGELAND PIPE LINE COMPANY LIMITED, *incorporated under the Laws of the Province of Alberta*

SECURITY FREEHOLD PETROLEUMS LIMITED, *incorporated under the Laws of Canada*

TRANSFER AGENTS

Common Shares

MONTREAL TRUST COMPANY,
Calgary, Montreal, Regina, Toronto, Vancouver and Winnipeg

MORGAN GUARANTY TRUST COMPANY OF NEW YORK,
New York

Preferred Shares

MONTREAL TRUST COMPANY,
Calgary, Montreal, Regina, Toronto, Vancouver and Winnipeg

STOCK EXCHANGE LISTINGS

Common Shares

TORONTO STOCK EXCHANGE
MONTREAL STOCK EXCHANGE
AMERICAN STOCK EXCHANGE

Preferred Shares

TORONTO STOCK EXCHANGE
MONTREAL STOCK EXCHANGE

AUDITORS

PEAT, MARWICK, MITCHELL & CO.,
Calgary

Hudson's Bay Oil and Gas Company Limited 1971 Annual Report

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